ACCESSION #: 9605280291
LICENSEE EVENT REPORT (LER)

FACILITY NAME: PILGRIM NUCLEAR POWER STATION PAGE: 1 OF 18

DOCKET NUMBER: 05000293

TITLE: Automatic Scram due to Turbine Vibration During Planned
Power Reduction
EVENT DATE: 04/19/96 LER #: 96-005-00 REPORT DATE: 05/20/96

OTHER FACILITIES INVOLVED: N/A DOCKET NO: 05000

OPERATING MODE: N POWER LEVEL: 22

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(iv)

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COMPONENT FAILURE DESCRIPTION:
CAUSE: X SYSTEM: TA COMPONENT: 86 MANUFACTURER: G080
X SB 20 XXX
REPORTABLE NPRDS: Y
Y

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On April 19, 1996, at 1016 hours, an automatic scram occurred at 22 percent reactor power while reducing power for a planned outage. The scram was initiated by vibration in the low pressure portion of the main turbine-generator. At 1018 hours, a high water level isolation occurred during scram recovery.

The cause of the scram was vibration in a portion of the new low pressure turbine. The low pressure turbine rotors have a monoblock design. The clearances between the new low pressure turbine rotor blades and turbine casing diaphragm are smaller than the previous low pressure turbine. The smaller clearances introduced different rub characteristics than the previous low pressure turbine. The high water level isolation was caused, in part, by decreasing reactor pressure that was due to a leak in

a turbine steam sealing system valve downstream of the main steam isolation valves.

Scram-related corrective action taken included increasing the vibration trip setting for the low pressure portion of the turbine and revision of related procedures. The high water level isolation-related corrective actions included valve repair.

This scram occurred with the reactor mode selector switch in the RUN position. The reactor vessel pressure was 944 psig with the reactor water temperature at the saturation temperature for the reactor pressure. The events posed no threat to the public health and safety.

END OF ABSTRACT

BACKGROUND

A shutdown of Pilgrim Station was planned for April 19, 1996, to begin a short maintenance outage. Key items planned for the outage were the replacement of the mechanical seal for the recirculation system loop 'A' pump, repair of the main steam relief valve RV-302-3B, repair of sample valve AO-220-44, and inspection of the internals of the feedwater system train 'A' feedwater heater E-102A. Other planned outage items germane to this report were the increase in the primary containment isolation control system group 1 high reactor water level trip setting and repair of the turbine steam seal system pressure relief valve PRV-3197.

On April 18, 1996, at 1200 hours, activities for de-inerting the primary containment atmosphere began.

At 1955 hours, the regional power authority (REMVEC) was notified of the planned power reduction and the power reduction began at 2006 hours.

At 2059 hours, while decreasing reactor power in accordance with procedures 2.1.5 attachment 'A', "Controlled Shutdown With Manual Scram," and 2.1.14, "Station Power changes," the turbine intercept valves #3 (IV-3) and #4 (IV-4) indicated a dual position indication, open and closed, instead of an open position. The indication occurred during a manual adjustment of the turbine speed/load changer to 77%. The turbine speed/load changer was not decreased to 77% and was left at 92% because of the position indications of valves IV-3 and IV-4. Caution tags were hung to document and control the turbine speed/load setting. Problem report (PR) 96.9189 was written to document the problem with the position indication of valves IV-3 and IV-4. The problem was later diagnosed as binding in the dash pot of the position transmitter for valves IV-3 and IV-4.

Activities for a backwash of the main condenser began as planned and the backwash began at 2306 hours.

Planned testing of the main steam isolation valves (MSIVs) via procedure 8.7.4.4, "Main Steam Isolation Valve Quarterly Operability," began at 0031 hours and was completed at 0256 hours on April 19, 1996.

Planned testing of the main turbine stop valves via procedure 8.A.9-2, "Turbine Test - Monthly, 70% Power," began at 0325 hours. At 0331 hours, turbine stop valve SV-3 was noted as not moving smoothly as expected and a maintenance work request tag was initiated. PR 96.9190 was written to document the operation of SV-3 during the surveillance. The problem was later diagnosed as sticking of the valve's pneumatic test cylinder.

By 0701 hours, the backwash of the main condenser was completed.

Feedwater Pump 'C' was removed from service and the electrolytic hydrogen water system was subsequently shut down as planned at 0740 hours.

At 0810 hours and at 39% reactor power, the rod worth minimizer (RWM) was bypassed for testing. This action was taken as allowed by procedure 2.1.5.

At 0852 hours, feedwater pump 'B' and condensate system pump 'C' were removed from service.

The intermediate range neutron monitors (IRMs) were fully inserted into the reactor core.

At 0913 hours, the feedwater heaters were removed from service.

Reactor water level control was changed from the three element control mode to the single element (reactor water level) control mode at 0919 hours.

At 0928 hours, feedwater regulating valve 'A' was removed from service.

The reading of IRM 'H' was noted downscale at 0930 hours and a LCO was initiated at that time. PR 96.9191 was written to document the problem.

Procedure 2.1.31 "Rod Worth Minimizer Operability," was completed at 0931 hours.

At 1009 hours, the augmented off gas system was removed from service with reactor power at 23%. Also at that time, Boston Edison Company system engineers and General Electric Company personnel were making preparations for troubleshooting the anomalous indications of the turbine intercept valves (IV-3 and IV-4) for resolution prior to removing the turbine-generator from service.

At 1013 hours, a control room panel C2L alarm A-3, "Turbine Vibration Hi," occurred. The vibration was at 8 mils. The turbine vibration recorder was then placed on high speed. Procedure 2.4.46, "Turbine Bearing Vibration," was entered and the procedure allowed operation at 10 mils for 10 minutes. An attempt was made to reduce turbine vibration by decreasing the turbine speed/load changer to 88%.

The status of systems just prior to the event were as follows. The circulating water system pumps 'A' and 'B' were in service providing normal cooling water to the main condenser. The recirculation system MG sets/pumps 'A' and 'B' were at the minimum speed with both controllers in the local manual control mode. The feedwater level control system was in the single element (reactor water level) control mode. The feedwater system regulating valve FV-642A was in the closed position and FV-642B was in service in the automatic control mode. The condensate system pumps 'A' and 'B' were in service and the feedwater system pump 'A' was in service. Reactor power was 22%. The reactor pressure was 944 psig with the reactor water level at +26 inches (narrow range). The turbine first stage pressure was 9395 psig (decreasing). The turbine speed/load changer was set at 88%. The suppression pool water level was in the normal range, at approximately -4 inches (LR-5038/5049), and the water temperature was 73 degrees F. The standby gas treatment system (SGTS) train 'B' was in service as part of de-inerting the suppression chamber atmosphere. The 4160v ac auxiliary power distribution system buses Al through A6 were being powered from the main generator via the unit auxiliary transformer with the fast transfer control switches in the ON position. The startup transformer was in standby service. The 345KV ac transmission lines 342 and 355 were energized. The 345KV ac switchyard ringbus was energized with the switchyard air circuit breakers (ACBs) 102, 103, 104 and 105 closed. The emergency diesel generators 'A' and 'B' were in standby service. The 23KV ac distribution system was energized. The shutdown transformer, station blackout diesel generator, and related bus (A8) were in standby service.

EVENT DESCRIPTION

On April 19, 1996, at 1016 hours, an automatic reactor protection system (RIPS) scram signal and scram occurred while at 22% reactor power. The scram was the result of an automatic trip of the turbine master trip solenoid (MTS-1). The trip of MTS-1 was the result of a turbine-generator high vibration trip signal. The vibration trip signal originated from vibration detectors associated with the low pressure turbine bearings #5 and #6 that increased rapidly to 12 mils.

The trip of MTS-1 resulted in the automatic initiation of a main turbine vacuum trip (VT-1) as designed and that initiated a designed trip of the turbine's emergency trip valve. The initiation of the trip valve, in turn, resulted in a reduction of turbine control oil flow and pressure. The reduction in control oil flow and pressure resulted in the following responses of the turbine's mechanical - hydraulic control system:

o Automatic initiation of the turbine acceleration trip relay. This resulted in the following designed responses:

o Automatic opening of oil pressure switches PS-37/38/39/40 that resulted in the actuation of the RPS (load rejection). The scram signal was the designed response to the load rejection with the turbine first stage pressure at 93-95 psig (decreasing).

o Automatic fast closure of the turbine control valves and intercept valves.

o Automatic actuation of the turbine load limit trip piston. This trip also results in the closing of the turbine control valves and turbine intercept valves.

o Automatic closing of the turbine intermediate stop valves.

o Automatic closing of the turbine stop valves.

The closing of the turbine intercept valves and intermediate stop valves and stop valves should have resulted in a trip of the turbine lockout relay 286-2. Lockout relay 286-2 is normally de-energized and is a General Electric Company type HEA61C relay located in control room panel C5. The coil of relay 286-2, however, failed and resulted in the generation of some smoke. Relay 62Y/G1, also normally deenergized and electrically connected in parallel with relay 286-2, energized as designed.

The RPS scram signal resulted in designed responses that included::

o Automatic insertion of the control rods.

o Automatic fast transfer of the source of 4160V ac power for emergency busses A5 and A6 from the unit auxiliary transformer (UAT) to the startup transformer (SUT).

The energizing of relay 62Y/G1 resulted in the automatic opening of 345KV ac switchyard ACBs 104 and 105. The opening of ACBs 104 and 105 resulted in designed responses that included an automatic transfer of the source of 4160V ac power for the auxiliary power distribution system. Buses Al through A4, aligned to the UAT, transferred automatically from the UAT to the SUT. Buses A5 and A6, previously transferred automatically from the UAT to the SUT as a result of the RPS scram signal, remained powered via the SUT.

The reactor vessel water level decreased to approximately +9 inches as expected due to the decrease in the void fraction in the reactor water. The decrease to less than the low reactor water level setpoint (calibrated at approximately +12 inches) resulted in the automatic initiation of the primary containment isolation control system (PCIS) and reactor building isolation control system (RBIS).

The PCIS initiation resulted in the following responses:

o Automatic closing of the primary containment system (PCS) group 2 isolation valves that were open, including the primary containment vent and purge valves that were open for de-inerting.

o The PCS group 3/residual heat removal (RHR) system shutdown cooling suction piping isolation valves, MO-1001-47 and -50, remained closed. The RHR system low pressure coolant injection loop 'A' valve MO-1001-29A and loop 'B' valve MO-1001-29B remained closed.

o Automatic closing of the PCS group 6/reactor water cleanup (RWCU) system isolation valves MO-1201-2, MO-1201-5, and MO-1201-80.

The RBIS initiation resulted in the automatic start of the standby gas treatment system (SGTS) train 'A' and automatic closing of the secondary containment ventilation supply and exhaust dampers. The SGTS train 'B' fan remained in operation.

Initial control room operator response included the following: The reactor mode selector switch was moved from the RUN position to the SHUTDOWN position and then to the REFUEL position, and a verification of the insertion of the control rods began. These actions were taken in accordance with procedure 2.1.6, "Reactor Scram." Emergency operating procedure EOP-01, "RPV Control," was entered because the reactor water level was +9 inches. Entry into EOP-01 is required if reactor water level is +9 inches or less. Forty-eight of the 145 CRD "full-in" lights were not illuminated on the reactor control panel display.

At 1017 hours, continuing operator response included actions to close the feedwater regulating valve 'B', closing the startup feedwater regulating valve, closing the downstream feedwater train 'A' block valve MO-3479 and train 'B' block valve MO-3480, and removing the feedwater pump 'A' from service. These actions were taken in accordance with procedure 2.1.6 due to increasing reactor water level, then at approximately + 20 inches and increasing rapidly. Feedwater flow into the reactor vessel was terminated when the reactor water level was approximately +23 inches (increasing). The +23 inches (increasing) was determined based on post trip review information that included operator statements and reactor water level recordings.

At 1018 hours, a PCIS group 1 isolation signal occurred due to high reactor water level (+48 inches). The group 1 isolation signal resulted in the automatic closing of the main steam isolation valves (MSIVs) and main steam drain valves. The closing of the MSIVs and drain valves eliminated the main condenser as a heat sink for reactor core decay heat generated steam.

Fire alarms on control room panels C1, C2, and C3 occurred at 1019 hours. Control room operator response included a report of smoke. The smoke, including a small flame, were due to the failure of the coil of the turbine lockout relay 286-2. A carbon dioxide extinguisher was directed at the turbine lockout relay 286-2. The smoke condition did not affect control room operations, and damage was limited to the turbine lockout relay coil.

At 1021 hours, the reactor pressure was approximately 820 psig with the reactor water level at approximately +57 inches and slowly increasing due to the decay heat related expansion of reactor water.

The main generator field breaker and exciter field breaker were manually opened at 1024 hours. This action was taken because the normally open contacts of relay 286-2 did not close due to the failure of the relay to energize. The normally open contacts close when the relay energizes and results in the automatic opening of the generator field breaker and exciter field breaker.

Also at 1024 hours, the RHR system loop 'A' was put into service in the suppression pool cooling (SPC) mode. These actions were taken in anticipation of the removal of steam heat that would be introduced into the suppression pool as a result of the expected start of the high pressure coolant injection (HPCI) system in the flow test mode for reactor pressure control.

The PCIS group 6 isolation signal was reset and the RWCU system was put into service at 1029 hours. This action was taken to reject reactor water inventory to the main condenser hotwell. At that time, reactor pressure was 890 psig and reactor water level was approximately +58 inches.

At 1032 hours, EOP-02, "RPV Control," was entered because the insertion to position 00 or 02 could not be determined for two control rods, 06-27 and 38-11. The neutron monitoring system intermediate range monitors were all indicating on range 1 and the source range monitors were indicating between 100 - 1000 counts. By 1035 hours, the insertion of control rod 38-11 to position 00 was verified.

The automatic initiation circuitry of the automatic depressurization system (ADS) was inhibited per EOP-02 at 1034 hours. The maximum reactor water level of +60 inches during the event occurred at that time.

At 1040 hours, the reactor mode switch was moved from the REFUEL position to the SHUTDOWN position. The steam jet air ejectors that are part of the main condenser gas removal system were also removed from service at that time.

The reactor pressure was then 920 psig and continuing to slowly increase due to decay heat.

The CRD system charging water valve HO-301-25 was closed and the CRD system pump 'A' was removed from service at 1043 hours. This action was taken to eliminate the CRD system as a source of unnecessary water into the reactor vessel and was in accordance with EOP-02.

The RHR system loop 'B' was put into the suppression pool cooling (SPC) mode at 1045 hours in anticipation of the addition of steam heat from the reactor vessel via the manual opening of one or more main steam relief valves. The reactor pressure was then at 950 psig (increasing) and the control room operator was directed to open main steam relief valves as necessary to control reactor pressure.

At 1048 hours, with reactor pressure at 974 psig, the maximum pressure during the entire event, the control room operator was directed to open main steam relief valves in the of sequence of 'C', 'D', 'A', as necessary to control reactor pressure in the range of 800 - 950 psig. Relief valve RV-203-3C (pilot serial number 1049) was manually opened via its control switch at that time.

The suppression pool water temperature was 74 degrees Fahrenheit (F) and slowing increasing, and the suppression pool water level was approximately 130 inches (LI-1001-604 A/B), equivalent to -3 inches (LR-5038/5049), at 1050 hours. Procedure 2.1.7, "Reactor Temperature and Pressure Checklist," was initiated at that time.

By 1051 hours, the reactor water level had decreased to +30 inches because of the removal of steam from the reactor vessel via the operation of relief valve RV-203-3C and reactor water inventory rejection to the main condenser via the RWCU system. Relief valve RV-203-3C was manually closed at that time.

The high pressure coolant injection (HPCI) system was put into service in the full flow test mode for reactor pressure control at 1051 hours.

At 1054 hours, the CRD system pump 'A' was started and feedpump 'A' was also started. At 1057 hours, the CRD system charging water valve HO-301-25 was reopened. These actions were part of configuring these systems for shut down lineup.

A reactor pressure range of 750 - 900 psig was established by 1100 hours via HPCI system service in the full flow test mode for reactor pressure control. After the PCIS group 1 isolation signal was reset, the outboard MSIVs were opened. Preparations for rejecting the suppression pool water inventory to the radwaste system also began at that time.

At 1101 hours, the HPCI system flow controller was changed from the automatic control mode to the manual control mode to facilitate HPCI system test flow to less than 3000 GPM. This action was taken because the HPCI pump discharge pressure, at approximately 1100 psig, did not decrease as expected when the position of the HPCI flow test valve MO-2301-10 was adjusted per procedure 2.2.21.5, "HPCI Injection and Pressure Control." The reactor pressure was approximately 800 psig at that time.

The HPCI system was removed from service for reactor pressure control at 1105 hours. The HPCI system engineer was contacted to investigate the anomalous discharge pressure indication and the engineer discussed the problem with the HPCI operator.

A reset of the RBIS began at 1103 hours.

At 1106 hours, EOP-03, "Primary Containment Control," was entered because the suppression pool water temperature was 80 degrees F due to the addition of steam heat from the reactor vessel via the previous opening of the main steam relief valve RV-203-3C and HPCI turbine steam exhausted to the suppression pool.

An attempt to open main steam drain valve MO-220-3, located downstream of the group 1 main steam drain isolation valves MO-220-1 and -2, was made at 1112 hours; but the valve would not open via its control switch in the control room. Two operators were sent to open the valve manually.

At 1113 hours, an initial entry into the drywell was made and feedpump 'A' was removed from service at that time.

The HPCI system was put into service in the full flow test mode for reactor pressure control at 1116 hours and the system automatically tripped as designed due to a high reactor water level (+45 inches). The nuclear operating supervisor directed the HPCI system controls be reset and, after the reset, the system was put back into the flow test mode for pressure control at 1119 hours. The HPCI system automatically tripped as designed due to high reactor water level at 1120 hours. The high water level was due to the increase in the reactor water void fraction resulting from the decrease in the reactor vessel pressure that was due to the removal of steam during HPCI turbine operation.

By 1124 hours, the reactor pressure was 772 psig and slowly increasing, and the reactor water level was +44 inches. The pressure was decreased by manually opening relief valve RV-203-3D (pilot serial number 1054). Relief valve RV-203-3D was closed at 1128 hours. This action was taken to maintain the reactor pressure in the 600 - 750 psig range. The reactor water level decreased further due to a decrease in the reactor water void fraction that resulted from a reactor pressure increase after relief valve RV-203-3D was closed. The decrease, to approximately -5 inches, resulted in an RPS scram signal, PCIS groups 2, 3, and 6 isolation signals, and an RBIS isolation signal. The control rods remained in the inserted position, the group 6/RWCU system isolation valves closed automatically. The secondary containment ventilation supply and exhaust dampers remained closed, and the SGTS train 'A' and train 'B' automatically started.

At 1126 hours, the CRD system charging water valve HO-301-25 was closed and the CRD system pump 'A' was removed from service at 1127 hours. This action was taken because there actor water level, then at +15 inches, was increasing. The reactor vessel pressure was 625 psig.

EOP-02 was exited at 1128 hours because all control rods were verified full-in. EOP-01 was entered at that time as required by the exit of EOP-02.

At 1130 hours, the HPCI system was put into service in the full flow test mode for reactor pressure control.

The main steam drain valve MO-220-3 was fully opened (manually) by 1132 hours. This allowed for equalizing the pressure across the MSIVs and later opening of the MSIVs.

At 1136 hours, the SGTS fan 'A' was stopped and activities for a reset of the RBIS and opening of the secondary containment ventilation supply and exhaust dampers began.

The inboard and outboard MSIVs were opened at 1149 hours. The flow path for steam to the turbine steam seals was established at 1151 hours, and the main condenser gas removal system steam jet air ejectors 'A' and 'C' were put into service at that time. These actions were taken as part of preparations for rejecting decay heat generated steam from the reactor vessel to the main condenser.

At 1152 hours, the reactor pressure was approximately 400 psig.

The CRD system charging water valve HO-301-25 was opened at 1153 hours.

At 1200 hours, the drywell floor and equipment sumps were pumped to the radwaste system. This routine action was taken in accordance with procedure 2.1.15, "Daily Surveillance Log." The ADS circuitry was restored to normal status (not inhibited), the HPCI system turbine speed was maintained at a minimum speed (2000 RPM), and the main condenser vacuum was restored as part of preparations for rejecting decay heat generated steam to the main condenser.

The NRC Operations Center was notified of the event in accordance with

10 CFR 50.72 at 1205 hours.

At 1206 hours, the HPCI system was removed from reactor vessel pressure control service.

Feedwater pump 'A' was removed from service at 1207 hours. The main condenser vacuum trip (VT-2) alarm was reset at that time. The reset allowed for turbine steam bypass valves operation for the rejection of decay heat generated steam from the reactor vessel to the main condenser.

At 1209 hours, the RBIS circuitry was reset and the SGTS was removed from service.

The hydrogen-oxygen (H2/O2) system was put into service in accordance with EOP-03 at 1209 hours.

At 1211 hours, the RPS was reset.

EOP-03 was exited at 1315 hours and suppression pool water temperature monitoring was terminated.

At 1340 hours, the HPCI system isolated automatically as designed due to low reactor pressure.

The RHR system loop 'A' was removed from service in the SPC mode at 1350 hours.

At 1413 hours, the reactor core isolation cooling (RCIC) system isolated automatically as designed due to low reactor pressure. The RCIC system was not operated at any time during the event.

The H2/O2 system was returned to standby service at 1448 hours.

At 1607 hours, the RHR system loop 'B' was removed from service in the SPC mode.

The steam jet air ejectors were removed from service at 1640 hours.

At 2045 hours, the recirculation system loop 'A' MG set/pump was removed from service.

After the reset of the PCIS group 3 circuitry, valves MO-1001-47, -50, -29A were opened and the RHR system loop 'A' was put into service in the shutdown cooling mode at 2246 hours. By 2311 hours, co shutdown conditions were achieved and the reactor head vent valves were opened.

A post trip review was conducted in accordance with procedure 1.3.37, "Post Trip Review." A critique of the event was also conducted in accordance with procedure 1.3.63, "Conduct of Critiques and Investigations." The post trip review and critique included applicable personnel including the operators on shift at the time of the event.

Problem reports were written to document the scram and other observations during or after the event and included the following. PR 96.9192 was written to document the turbine high vibration scram. PR 96.9193 was written to document the problem with lockout relay 286-2. PR 96.9194 was written to document the problem with valve MO-220-3. PR 96.9195 was written to document the anomalous HPCI pump discharge pressure indication. PR 96.9206 was written to document the problem with verifying the position of control rods beyond position 02. PR 96.0148 was written to document the conservative turbine first stage pressure reset setting of 60 psig (decreasing).

CAUSE

The cause of the event was turbine-generator shaft vibration sensed at the location of low pressure turbine bearings number 5 and 6. The vibration was caused by rubbing between the new low pressure turbine rotor blades and turbine casing diaphragms. New low pressure turbine rotors, rotor blades, and casing diaphragms were installed in the last refueling outage (RFO-10) in the March - June 1995 time frame. The clearances of the new low pressure turbine blades and casing diaphragms are smaller than the previous low pressure turbine units. The smaller clearances introduced different rub characteristics than previous plant shutdowns with the former low pressure turbine units.

The main turbine is a tandem-compound six flow unit, 1 high pressure double flow unit and 2 low pressure double flow units. The new low pressure turbine rotors were dynamically tested prior to installation. The turbine-generator, including the new low pressure turbine, was tested after installation of the new low pressure turbine as part of testing during startup from RFO-10. Prior to the scram on April 19, 1996, no shut downs or scrams had occurred since startup following RFO-10.

The cause of the PCIS group 1 isolation signal was high reactor water level. The isolation was caused by 2 simultaneous conditions that existed after the initial reactor water level decrease that occurred due to the scram. The first condition was the normal reactor water level increase due to feedwater flow and normal reactor pressure decrease due to reduced steam generation and steam rejection to the main condenser via the main steam lines and turbine bypass valves. The second condition was the abnormal, additional pressure reduction due to steam leaking from the turbine steam sealing system pressure relief valve PRV-3197, located downstream of the main steam isolation valves and upstream of the turbine stop valves. Steam voids re-form, after the scram, due to latent core heat (decay heat). As reactor pressure decreases, these voids expand and contribute to the reactor water volume and, hence, reactor water level. Another effect that contributes to increased reactor water level is the heating of the sub-cooled feedwater that expands, by decay heat, and increases the reactor water volume and, hence, reactor water level.

CORRECTIVE ACTION TAKEN

Corrective action taken related to the scram signal included the following:

The turbine vibration trip setting that initiates a trip of the turbine due to high vibration was changed while shut down. The change, from 12 mils to 14 mils, for the low pressure turbine bearings 3, 4, 5, and 6 was made via an engineering modification document (FRN 96-04-35).

Alarm response procedure ARP-C2L was revised to rev. 9. The revision included a decrease in the "Turbine Vibration Hi" annuciator alarm setting to 5 mils (increasing) and the increase in the trip setting, to 14 mils, for the low pressure turbine bearings 3, 4, 5, and 6. Procedure 2.4.46, "Turbine Vibration Malfunction," was revised (to rev. 10) to incorporate the change in the trip setting for the low pressure turbine bearings 3, 4, 5, and 6.

Temporary procedure (TP) 96-014 (rev. 0), "Operational Guidance for Turbine Vibration Limits and Trips During Startup," was written to provide guidance for rolling the turbine-generator and turbine-generator vibration limits and trip during startup and power ascension. Procedure 2.1.1, "Startup From Shutdown," was revised (to rev. 83). The focus of the change was to reflect the change to procedure 2.4.46 and the issuance of TP 96-014.

Information regarding the above noted procedure changes, and changes to procedures 2.2.21.5, "HPCI Injection and Pressure Control," and 8.5.4.1, "HPCI System Pump and Valve Quarterly Operability," that are discussed in the next section of this report, was promulgated to operations personnel prior to startup.

Corrective action taken for the PCIS group 1 isolation included the repair of the turbine steam sealing system pressure relief valve PRV-3197. The PCIS group 1 isolation setting was increased from approximately +48 inches to approximately +55 inches. The setting was changed in accordance with a change to technical specifications (amendment #164) via an engineering modification document (PDC 94-30). Applicable procedures were revised.

Startup activities began on April 22, 1996. The changes to the low pressure turbine bearings 3, 4, 5, and 6 alarm and trip settings were made on April 23, 1996. Procedure 2.1.1, "Startup Checklist," is used for plant startup and included the following. The turbine-generator began to be rolled via its turning gear at 2400 hours on April 23, 1996. The reactor head vent valves were closed at 0006 hours and reactor criticality was achieved at 0441 hours on April 24, 1996. The HPCI and RCIC systems' low reactor vessel pressure isolation signals were reset at 0646 hours. The turbine steam bypass valve BPV-1 was open at 1141 hours with the reactor vessel pressure at the electric pressure regulator setting and reactor power then at 5 percent. The reactor mode selector switch was moved from the STARTUP position to the RUN position at 1547 hours. A pre-evolution briefing on procedure TP 96-014 was conducted at 2045 hours. The roll of the turbine-generator began at 2111 hours on April 24, 1996. Procedure TP 96-014 attachment 1, "Turbine Roll and Synchronization," was used for the turbine-generator roll until 2326 hours on April 24, 1996, when the turbine-generator was synchronized to the transmission system. After synchronization to the transmission system, procedure TP 96-014 was used in conjunction with procedure 2.1.1.

The scram bypass function is accomplished by the analog trip system master control units PIS-504A/B/C/D. Procedures 8.M.1-32.1/.2/.3/.4 govern the calibration of trip units PIS-504A/B/C/D and were revised to change the reset setting. The trip units were recalibrated to reset at approximately 102 +/- 6 psig (decreasing) on May 1, 1996. The focus of the change was for the trip units to reset as close to the 108 psig (increasing) trip setting as possible. The calibration change was made via an engineering modification document (FRN 96-04-34).

OTHER ACTION TAKEN WHILE SHUT DOWN

The anomalous HPCI system pump discharge pressure noted while the HPCI system was in the flow test mode for reactor pressure control was evaluated. The evaluation included the design of the flow test restricting orifice RO-2301-59 and flow test valves MO-2301-10 and MO-2301-15. The restricting orifice was disassembled and found to be free of foreign material. Valves MO-2301-10 and MO-2301-15 were stroked and found to operate properly. Procedure 2.2.21.5 was revised (to rev. 5) to direct the operator to reduce the pump flow setpoint along with jogging open valve MO-2301-10 to reduce pump discharge pressure. Procedure 8.5.4.1 was revised (to rev. 50) to add steps to slowly jog open valve MO-2301-10 and record pump discharge pressure at 4250 gpm and 3000 gpm.

The failed coil of turbine lockout relay 286-2 was removed and replaced with a new coil. The replacement coil was installed and adjusted per manufacturer instruction. The relay was mechanically tripped several times to verify free operation. The relay was operated electrically 3 times by applying rated voltage to the coil and the operation times were within manufacturer's tolerance. The lockout relay trip circuit was resistance tested and was found satisfactory. The relay was tested 3 times through its logic circuit with satisfactory results in accordance with procedure 3.M.3-39, "Turbine/Generator Calibration of Relays, Lockout Test and Associated Annunciation Verification." The generator lockout relay 286-1, also a type HEA61C relay and the only other type HEA61C relay installed at Pilgrim Station, was also tested with satisfactory results in accordance with procedure 3.M.3-39.

The limit switch cartridge and associated pinion for the main steam drain valve MO-220-3 were replaced. The inability to open nonsafety-related valve MO-220-3 via its control switch was due to improper shimming of its limit switch gear box during the valve's overhaul in the last refueling outage (RFO-10). Valve MO-220-3 is a 2" globe-type valve manufactured by NEWCO. A vendor code for NEWCO is not currently listed in the Nuclear Plant Reliability Data System (NPRDS).

The position transmitters for the turbine intercept valves were disassembled. The transmitter for intercept valves IV-1 and IV-2 was found clean. The transmitter for valves IV-3 and IV-4 was cleaned.

The pneumatic test cylinders of the turbine stop valves (SV-1, SV-2, SV-3, and SV-4) were lubricated and exercised.

The pilot valve (serial number 1025) of relief valve RV-203-313 was replaced with a spare, test certified pilot valve (serial number 1046). The valve was tested with satisfactory results in accordance with procedure 8.5.6.2, "Special Test for ADS System Manual Opening of Relief Valves." The test was conducted at 1900 hours on April 24, 1996, as part of the plant startup.

The recirculation system loop 'A' pump mechanical seal was replaced. The internal of feedwater heater E-102A was inspected. Air operated valve AO-220-44 was repaired.

OTHER ACTION PLANNED

The rod worth minimizer (RWM) will be evaluated. The focus of the evaluation is for the possible use of the RWM as an additional means for verifying the insertion of the controls rods after a scram.

This report will be included in the plant status update training program.

SAFETY CONSEQUENCES

This event posed no threat to the public health and safety.

The load rejection experienced during this event is bounded by the transient analysis described in the Updated Final Safety Analysis Report, section 14.4.3, "Generator Load Rejection Without Bypass."

The scram signal was the designed response to the load rejection with the turbine first stage pressure at approximately 93-95 psig (decreasing), greater than the scram bypass reset setting that was calibrated at approximately 60 psig (decreasing). The analytical limit for the bypass is less than approximately 176 psig first stage pressure that corresponds to 45 percent of rated core thermal power (1998 MWt). The bypass functions to bypass the turbine stop valves closure scram function and turbine control valves closure scram function. The bypass is permissible at lower reactor power levels because the high neutron flux scram function and high reactor pressure scram function are adequate for reactor protection.

The decrease in the reactor vessel water level was the expected response to the scram and accompanying shrink (i.e ., decrease, in the void fraction in the reactor vessel water). The PCIS and RBIS actuations resulting from the scram were the expected designed responses to a low reactor vessel water level condition, i.e., less than + 12 inches.

The technical specification table 3.2.13 trip setting for automatic actuation of the core standby cooling systems (CSCS) is approximately -46.3 inches. During the event, the lowest reactor vessel water level that occurred, -5 inches, was approximately 41 inches above the CSCS setpoint. In addition, the level was approximately 122 inches above the level (-127 inches) that corresponds to the top of the active fuel zone.

The CSCS consists of the HPCI system, automatic depressurization system (ADS), core spray system, and RHR system/LPCI mode. Although not part of the CSCS, the reactor core isolation cooling (RCIC) system is capable of providing water to the reactor vessel for high pressure core cooling, similar to the HPCI system. The ADS is a backup to the HPCI system and functions to reduce reactor vessel pressure to enable low pressure core cooling provided independently by the core spray system and RHR system/LPCI mode. The CSCS and the RCIC system were operable.

The lowest reactor vessel water level that occurred (-5 inches) was greater than the setpoint, calibrated at approximately -46.3 inches, that initiates the anticipated transient without scram (ATWS) system functions for a recirculation pump trip (RPT) and alternate rod insertion (ARI). The highest reactor vessel pressure that occurred, 944 psig, was less than the setpoint, calibrated at approximately 1175 psig, that initiates the ATWS system RPT and ARI functions and the setpoint, calibrated at approximately 1400 psig, that initiates the ATWS system function for a feedpump trip.

The highest reactor vessel water level that occurred was +60 inches. The level was less than the level, approximately +112 inches, corresponding to the bottom of the main steam system piping.

The highest reactor vessel pressure that occurred was 944 psig and occurred at the time of the scram. The pressure was less than the technical specification 3.6.D setting of 1115 +/- 11 psig for the main steam relief valves and was less than the setting of 1240 +/- 13 psig for the main steam safety valves. The pressure was less than the technical specification table 3.1.1 setting of less than approximately 1063 psig for the high reactor pressure scram function.

The highest suppression pool bulk water temperature that occurred was 83 degrees F. The temperature was less than the maximum water temperature of 120 degrees F specified by technical specification 3.7.A.1.h during reactor vessel isolation conditions.

Technical specification 3.7.A.1.m specifies the suppression pool/chamber be maintained between -6 inches and -3 inches which corresponds to a downcomer submergence of 3.00 and 3.25 feet, respectively. The highest suppression pool water level that occurred was approximately -1 inches (LR-5038/5049), equivalent to approximately +132 inches (Ll-1001 -604A/B). The level was less than the level corresponding to the maximum suppression pool volume of 94,000 cubic feet specified by technical specification 3.7.A.1.b. A suppression pool volume of 94,200 cubic feet corresponds to a level of +6 inches (LR-5038/5049) or 139 inches (Ll-1001-604A/B). The level was less than the settings of level switches LS-2351A/B that control the automatic positioning of the suppression pool/HPCI pump suction valves.

This event was submitted in accordance with 10 CFR 50.73(a)(2)(iv) because the actuation of the RPS was not planned.

This report was also submitted in accordance with 10 CFR 50.73(a)(2)(iv) because the PCIS group 1 isolation at 1018 hours (after the scram) and the PCIS Group 6 isolation and RBIS isolation at about 1128 hours were not planned.

SIMILARITY TO PREVIOUS EVENTS

A review was conducted of Pilgrim Station LERs submitted since 1984. The review focused on LERs submitted in accordance with 10 CFR 50.73(a)(2)(iv) that involved a load rejection or similar scram. The review identified load rejection scrams reported in LERs 85-025-00, 90-008-00, 92-016-00, 93-004-00, and 94-005-00. None of these LERs involved a scram initiated by turbine vibration or the turbine vibration detection system. The review, however, identified LER 85-009-00 that involved a scram initiated by the turbine vibration detection system.

For LER 85-009-00, an automatic scram occurred on April 4, 1985, while at 85 percent reactor power. The scram occurred while reactor power was being reduced in response to a high turbine vibration alarm originating from the turbine-generator bearing number 9 (generator exciter front standard) vibration detector. The detector tip was found damaged. The tip damage was the result of a pin-hole sized lube oil orifice that became blocked and prevented adequate lubrication at the point where the vibration detector tip rides on the turbine-generator shaft. Corrective action taken included cleaning the orifice, a flush of the lubricating oil supply piping, and replacement of the vibration detector. The orifice and detector for bearing number 10 were inspected with satisfactory results.

ENERGY INDUSTRY IDENTIFICATION SYSTEM (EIIS) CODES

The EIIS codes for this report are as follows:

COMPONENTS CODES

Relay, locking-out 86
Turbine TRB
Valve, electrically
operated (MO-220-3) 20
Valve, relief (PRV-3197) RV

SYSTEMS

High pressure coolant
injection (HPCI) system BJ
Main steam system SB
Main turbine system TA

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10 CFR 50.73

Boston Edison
Pilgrim Nuclear Power Station
Rocky Hill Road
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E. T. Boulette, PhD May 20, 1996
Senior Vice President - Nuclear BECo Ltr. #96- 052

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D.C. 20555

Docket No. 50-293
License No. DPR-35

The enclosed Licensee Event Report (LER) 96-005-00, "Automatic Scram due to Turbine Vibration During Planned Power Reduction," is submitted in accordance with 10 CFR 50.73.

In this letter, the following commitments are made:

o Evaluate the rod worth minimizer as a possible means of verifying control rod insertion after a scram.

o Include this report in the plant status update training program.

Please do not hesitate to contact me if there are any questions regarding this report.

E. T. Boulette, PhD

DWE/dmc/9600500

cc: Mr. Thomas T. Martin
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Sr. NRC Resident Inspector - Pilgrim Station

Standard BECo LER Distribution

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